Exhibit 10

IN THE UNITED STATES DISTRICT COURT

FOR THE SOUTHERN DISTRICT OF TEXAS HOUSTON DIVISON

Civil Action No. 4:10-cv-4969

Environment Texas Citizen Lobby, Inc., and Sierra Club (Plaintiffs) v. ExxonMobil Corporation, ExxonMobil Chemical Company, and ExxonMobil Refining and Supply Company (collectively "Exxon")

Hon. David Hittner

U.S. District Judge

EXPERT REPORT

OF

DR. RANAJIT (RON) SAHU

Ranajit Sahu

ON BEHALF OF THE PLAINTIFFS

MARCH 13, 2012

TABLE OF CONTENTS

Information Required by the Federal Rules of Civil Procedure

The following is a list of the items required by the Federal Rules of Civil Procedure:

1. This report contains my opinions, conclusions and the reasons therefore;
2. I do not have any exhibits to be used in summary of, or support for, my opinions with this report other than what is provided with this report and other reports submitted in this action;
3. A statement of my qualifications is contained in Attachment A;
4. A list of publications I authored within the last ten years is shown in Attachment B;
5. My compensation for the preparation of this report and my testimony is included in Attachment C;
6. A statement of my previous testimony within the preceding four years as an expert at trial or by deposition is contained in Attachment D; and
7. Attachment E lists the information I considered in forming my opinions.
8. Attachments F and G contain tables showing example events that I analyzed as well as ratios of steam to waste gas flow rates for selected events and times, respectively.
9. Attachments H and I show events where flares were smoking or had pilot flame outages, respectively.

The opinions expressed in the report are my own and are based on the data and facts available to me at the time of writing. Should additional relevant or pertinent information become available, I reserve the right to supplement the discussion and findings in my report.

I. EXPERIENCE

I, Ranajit Sahu, have over twenty-one years of experience in the fields of environmental, mechanical, and chemical engineering, including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

I have a B.S., M.S., and Ph.D. in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute of Technology (Caltech) in Pasadena, California. My research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants.

I have over nineteen years of project management experience and have successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public.

I have provided consulting services to numerous private sector, public sector, and public interest group clients. My major clients over the past eighteen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including the US EPA, the

states of New York, New Jersey, New Mexico, Pennsylvania, the US Dept. of Justice, California DTSC, various municipalities, etc.). I have performed projects in 48 US states, numerous local jurisdictions, and internationally.

In addition to consulting, I have taught numerous courses in several Southern California universities, including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past eighteen years. In this time period I have also taught at Caltech, my alma mater, at USC (air pollution) and at Cal State Fullerton (transportation and air quality).

I have and continue to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies.

Additional details regarding my background and experience can be found in my resume provided in Attachment A and in the list of publications and presentations provided in Attachment B. Attachments C and D contain a statement of compensation and my previous expert witness experience, respectively.

II. SUMMARY OF REPORT

For this proceeding, I have been asked to provide opinions and a report, based on my educational experience, my training, as well as my work experience as a consultant and practitioner, that addresses the following items:

1. Are the quantities of emissions of various air pollutants estimated by Exxon to have been emitted by various flares[1] located at its highly-integrated Baytown, Texas, Complex[2] during each of the upsets that occurred during the times of interest in this matter, likely to be accurate?

2. Are all likely pollutants that could be emitted from the flares during the various events in question accounted for?

3. Are the impacts (i.e.., the estimated ground-level concentrations in micrograms/cubic meter) of the flare emissions as modeled in various instances by Exxon's consultant, SAGE Environmental Consulting ("SAGE"), likely to be accurate?

4. Are there measures that Exxon can take, or could have taken, to minimize or reduce pollutant emissions from flares?

Based on my review of the materials associated with the case provided to me by counsel at my request; my personal observations and information gained during a site inspection of the Baytown refinery and chemical plant on February 28, 2012 (the olefins plant was not included in the inspection tour because of work going on at that facility); my familiarity and review of relevant agency guidance; my knowledge of combustion processes acquired over the last 29 years; my familiarity with refinery processes and operations; and my familiarity with the flares from which the vast majority of emissions

[1] Although emissions of various pollutants occurred from other sources besides flares during the specific events that are the subject of this matter, I have focused specifically on flare emissions in my report.

[2] The Complex consists of a Refinery, a Chemicals Plant and an Olefins Plant, all of which are tightly integrated in terms of materials, intermediates, and utilities. Currently, 5 Federal Title V Operating Permits, issued by the Texas Commission on Environmental Quality (TCEQ) contain air quality conditions for the operation of the Complex.

in the matter at hand occurred, it is my opinion that the answers to the first three questions posed above is No. And, the answer to the last question posed above is Yes.

It is my opinion that the actual quantity of pollutant emissions for the events in question, even for those pollutants that Exxon did consider, have been underestimated by Exxon. As a related matter, it is my opinion that there are likely numerous other events that should have been publicly reported but were not, because estimated emissions were below reporting thresholds, since Exxon's emissions calculation approach is underestimating actual emissions from the flares.

It is my opinion that there is no question that Exxon did not consider numerous other pollutants that could be emitted by the flares during the events in question.

It is my opinion that the modeled impacts associated with the flare emissions in question are also incorrect and have also been underestimated. It is my opinion that actual emissions and their impacts could be significantly greater that what has been estimated by Exxon and its consultants.

It is my opinion that Exxon can take many actions in order to significantly reduce its flaring and resultant emissions, for both routine and non-routine events. Multiple refineries operating in California, including an Exxon refinery, have demonstrated that flaring events and emissions can be significantly reduced by following a systematic approach embodied in a dynamic flare management plan. Beginning with a thorough understanding of the root cause of every event, and then implementing actions to eliminate/minimize such causes in the future, flaring can be reduced considerably. Action will likely involve capital investments such as adding flare gas recovery systems, including compressors, adding spare capacity to existing systems and compressors, and improving operational practices, maintenance procedures, and training. By doing these, flaring can be reduced and each flare can go back to fulfilling its intended purpose: i.e., acting as a safety device as opposed to masquerading as an unreliable and uncertain air pollution control device.

III. BACKGROUND

Pursuant to regulations and its various operating permits, Exxon reports unauthorized emissions of various pollutants from upset events at the Baytown Complex. If, based on calculations that it does using data obtained from process conditions, the calculated emissions of various pollutants during these events are greater than reporting thresholds, then such events are reported to the TCEQ State of Texas Environmental Electronic Reporting System (STEERS).[3] Initial Notification and Final Reports for various events are provided to TCEQ. TCEQ occasionally requires Exxon to conduct air dispersion modeling to assess the impact of these emissions releases on ambient air quality (i.e., by calculating the expected concentrations of various pollutants) just outside the Complex (i.e., at the fenceline) where public exposures can occur. Once pollutant concentrations are determined using a dispersion model, Exxon's consultant compares the model-predicted concentrations with standards such as the National Ambient Air Quality Standard (NAAQS), the Texas Effects Screening Levels (ESLs), etc., depending on the pollutant (I refer to the reports of these modeling exercises as "SAGE reports," named after the consulting firm which has conducted the modeling demonstrations that I have reviewed). If background concentrations for the pollutant are available, they are included in this assessment – i.e., the concentrations resulting from the event are added to the background concentrations in the ambient air, before a comparison is made to the appropriate standard.

I have reviewed numerous STEERS and SAGE Reports as part of developing my opinions in this report. Attachment F shows examples of such events, along with details such as which part of the Complex the event took place at (i.e., refinery, chemical plant or olefins plant), the specific flares that were involved in the event, and the Exxon-estimated emissions of various pollutants that were emitted during the event. These are examples only, and are provided for illustrative purposes only.

[3] https://www6.tceq.texas.gov/steers/

In many (but not all) instances, these unauthorized emissions are due to releases solely from the various flare systems operating at the Complex.[4] In other instances, emissions occur from flares as well as other emission points. My report will only focus on flare emissions.

All flares discussed in this report are elevated, open flares. Basically, each flare consists of piping that feeds the waste gases (i.e., the gases to be flared) to the top of the flare structure (typically a derrick or similar structure) where they are ignited by a pilot flame. The pilot flame, which should always be present, is generally supported by natural gas. In addition, all but one of the flares in question have "steam-assist" – i.e., steam is provided at the flare tip in order to avoid smoking conditions.

The figure below shows a schematic diagram of a refinery flare system,[5] along with how flare gases are ordinarily routed to the refinery fuel gas system via flare gas recovery compressors. Routing waste gases to, and maximizing their use in, the refinery fuel gas system can reduce flaring and also minimize the need for purchased fuel gas.

[4] Other release points can include process piping, compressor seals, fugitive emissions from valves etc. In this report, I focus only on flare releases.

[5] Taken from Flare Minimization Plan, Chevron Products Company, Richmond, CA, Updated October 1, 2010. Available at http://www.baaqmd.gov/Divisions/Compliance-and-Enforcement/Refinery-Flare-Monitoring/Flare-Minimization.aspx

Figure 1-1, Simple Schematic - Flare System with Flare Gas Recovery

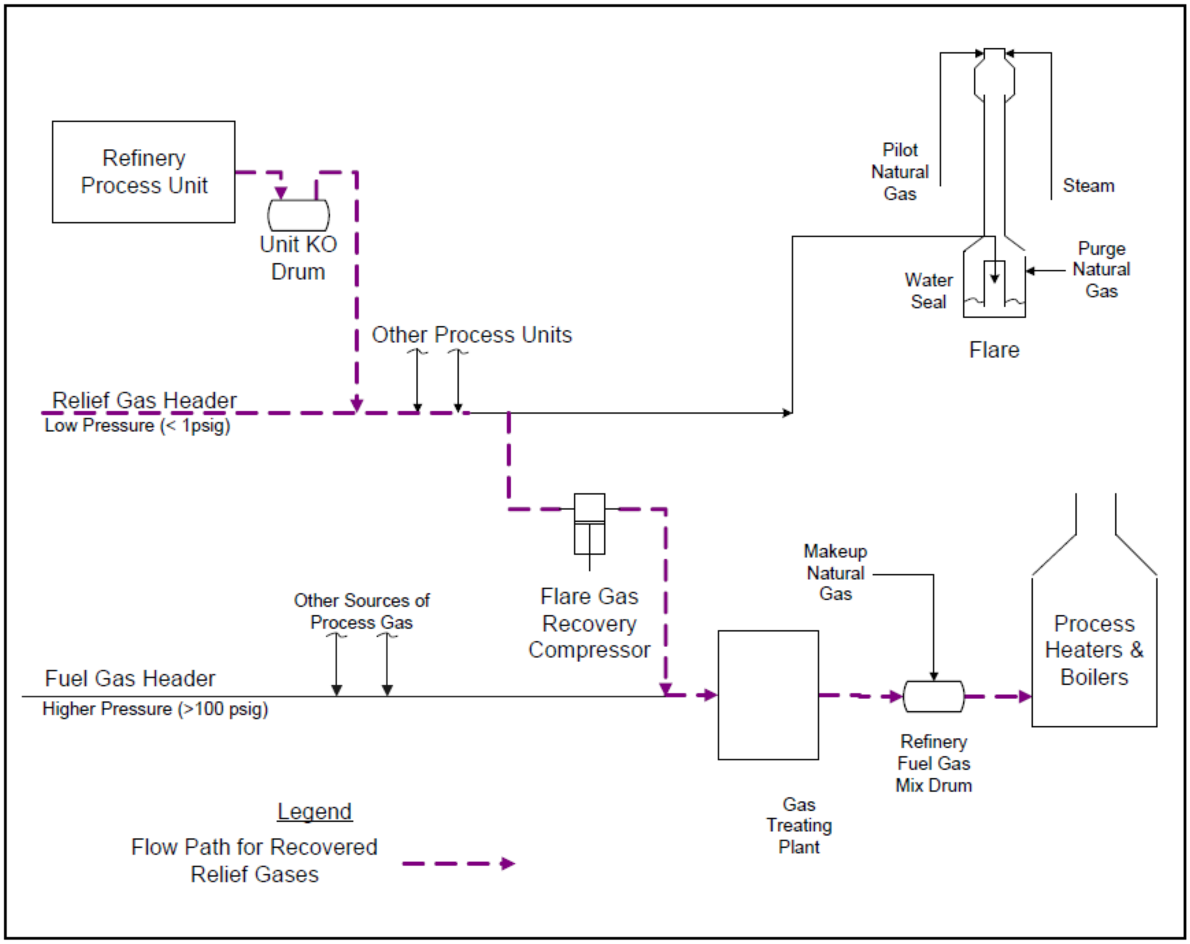
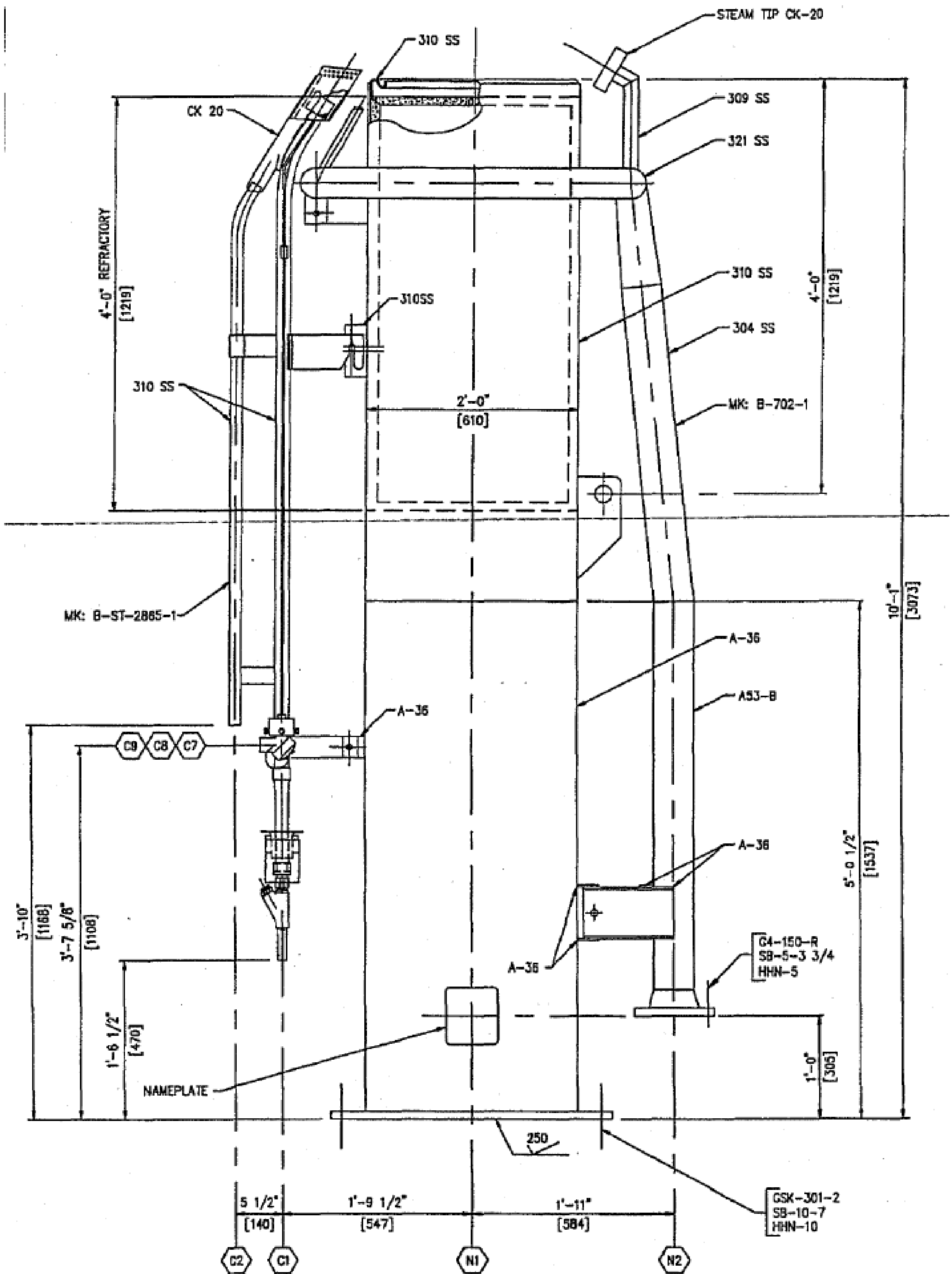


Figure 1-2 below shows an example of a flare tip (from Flare #4 at the Baytown Complex). This flare has three pilot flames, one of which is shown in the cross-section (to the left) below. Also shown is the steam header to the top right. As shown in the figure, this flare diameter is 2 feet or 24 inches.



ELEVATION

MK: B-301-1

P/N 1141843

Figure 1-2 – Typical Flare Tip Diagram (Elevation)[6]

Figure 1-3 below shows the top or plan view of the same Flare #4 depicted above (in Figure 1-2). The three pilots can be seen and the various steam injection ports can also be seen in this figure.

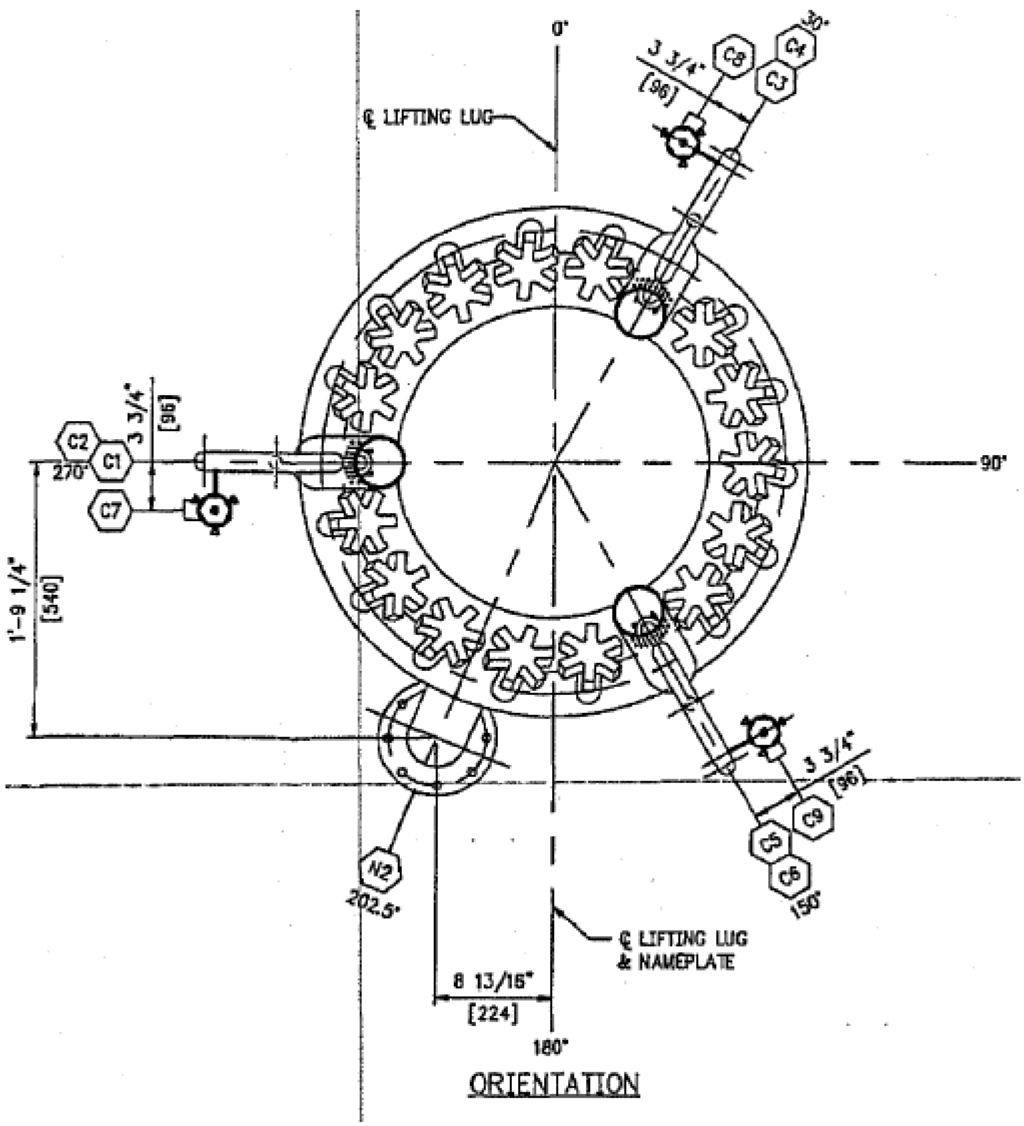


Figure 1-3 – Typical Flare Plan View[7]

Since flares are basically large Bunsen burners with open flames, they cannot be directly monitored for emissions, as opposed to exhaust stacks from combustion heaters or boilers, where

[6] See EOMCS00000004.
[7] See EOMCS00000004.

Continuous Emissions Monitors (CEMS) for various gases such as CO, NOx, SO2, VOCs, CO2, O2, HCl, etc., can be located.

Flares can "destroy" some portion of certain pollutants, such as hydrocarbons and sulfur-containing compounds. In this context, "destruction" means that the chemicals in question are converted to other forms that are then emitted into the atmosphere. For example, if a hydrocarbon were fully combusted in the flare (but it is important to note that, in reality, there is no possibility of such complete combustion at a flare or, for that matter, in any combustion device), the products of such complete combustion would be water vapor and carbon dioxide. In practice, as I will discuss later, flare combustion is a messy process that invariably creates and emits numerous other species of pollutants (I will refer to these as "products of incomplete combustion," or "PIC"). For example, oxides of nitrogen (NOx), are created during the combustion process in the flares. So is carbon monoxide (CO). Sulfur compounds, such as hydrogen sulfide (H2S) can be oxidized into forms such as sulfur dioxide (SO2) and sulfur trioxide (SO3). The latter can combine with water vapor to form various acids such as sulfuric acid mist (H2SO4).

To describe "destruction" of pollutants in the flares, Exxon uses the term "control efficiency" or CE, which I will also use for the sake of consistency. Basically, for a pollutant that is disposed of via the flare and which is likely to be combusted (such as any hydrocarbon or H2S), the control efficiency simply refers to the fraction of the input mass of the pollutant that is destroyed or converted in the flare. Thus, unless the control efficiency is 100% (or CE=1), some fraction of the input mass is not destroyed and this 1-minus- CE fraction of the input mass is emitted to the atmosphere. Thus, if control efficiency is 95% (or CE = 0.95), then 5% of the input mass (1 – 0.95 = 0.05) is emitted to the atmosphere (along with any PICs). Of course, CE is only relevant for pollutants that are sent *to* a flare. It is not relevant for pollutants that are created *in* the flare itself.

There are five different flare systems (each consisting of several individual flares) supporting the Refinery, the Chemical Plant, and the Olefins Plant in the Complex. The Title V permits list these flares. Briefly, flares 3, 4, 5, 6, 11, 14, 15, 16, 17, 18, 19, 20, 21, 22, 25, 26, 27 and 29 are

located at the Refinery.[8] Flares 9, 23, 24, and 28 are located at the Chemical Plant.[9] Flare 12 is located at the Butyl unit.[10] And, the Olefins Plant contains the Primary (Base), Secondary, and BOPX flares.[11] All of these flares are elevated (i.e., the flare itself is located several hundred feet above ground), and (with the apparent exception of Flare 28) are steam assisted. As shown in the example figures earlier, in a steam assisted flare, the exhaust or waste gases are commingled with steam, which is used to entrain air into the waste gases in order to allow for "smokeless" combustion. Steam is also used to cool the flare tips and other metal surfaces from the intense heat and radiation at the flare. Exxon provided steam and waste flow gas rates associated with these flares for the events in question and I have reviewed those.[12] I will discuss that later.

The table below shows the height, diameter (where available) and number of pilots for the various flares present at the Complex.

Location	Flare Description	Flare #	HEIGHT (FT)	# OF PILOTS	INSIDE TIP DIAMETER (IN or FT)
Refinery	FLARE STACK 19 (FNCC)	FL19	280	3	20 in
Refinery	FLARE STACK 20	FL20	280	3	4 ft 8 in
Refinery	PS8	FL21	280	4	4 ft
Refinery	FLARE STACK 22 (FNCC)	FL22	280	3	20 in
Refinery	FLARE STACK 25 (FXK)	FL25	280	3	2 ft 6 in
Refinery	F.X.K. TO FLARE	FL26	50	2	4 ft 8 in
Refinery	FLARE STACK 27 (PS7)	FL27	280	3	3 ft
Refinery	FCCU2	FL3	252	3	2 ft
Refinery	FLARE STACK 05 (WLFS)	FL5	248	3	2 ft
Refinery	FLARE STACK 06 (WLFS)	FL6	248	3	2 ft
Refinery	ALKY. TO W.L.F.S.	FLARE04	290	3	2 ft
Olefins	BAYTOWN OLEFINS PLANT	FLARE1	393	4	2 ft
Refinery	FCCU3	FLARE11	304	3	2 ft
Refinery	FCCU3	FLARE14	304	3	2 ft
Refinery	M.E.K. TO E.L.F.S.	FLARE15	315	3	2 ft 6 in
Refinery	D.A.U. TO E.L.F.S.	FLARE16	315	3	2 ft 6 in

[8] See EOMCS00001726-EOMCS00001727
[9] See EOMCS00001216
[10] See EOMCS00001031
[11] See EOMCS00000959, EOMCS00000961, and EOMCS0000964.
[12] With respect to Flares 12, 19, and 22, I did not receive such data until March 7, 2012 (it is my understanding Plaintiffs' counsel did not receive it until March 6, 2012) and I have not had a chance to fully review it before finalizing this report. I reserve the right to supplement my report with information obtained from this additional data.

Refinery	PS8	FLARE17	280	3	2 ft
Refinery	FLARE STACK 18 (FNCC)	FLARE18	280	4	4 ft
Olefins	ETHYLENE PLANT FLARE	FLARE2	415	4	2 ft
Olefins	BAYTOWN OLEFINS PLANT EXPANSION	FLAREX	400	4	2 ft
Chemicals	FLARE STACK 09	FS09	190	3	1 ft
Chemicals	BAYTOWN POLYMERS CENTER FLARE LOSSES	FS12	199	3	1 ft
Chemicals	FLARE STACK 23	FS23	451	3	1 ft
Chemicals	PROCESSES ROUTED TO FS09, FS23, FS24	FS24	400	3	1 ft
Chemicals	SYNGAS UNIT FLARE # 28	FS28	305	3	1 ft

As can be seen, the flare heights can vary considerably, ranging from 50 ft. to over 450 ft. Diameters range from 1 ft. to over 4 ft.

When unauthorized emissions occur at a flare, Exxon estimates the emissions of various pollutants to the atmosphere in a two step process. First, it estimates the hourly quantities (in lb/hr) of a given pollutant that are sent (i.e., input) to the flare in question. These "input" masses are, in turn, estimated using: data on pollutant concentrations in the waste gases, which are either periodically sampled or estimated based on process knowledge; and the flow rate of the waste gases along with the gas temperature and other parameters. In the second step, Exxon assumes that all of these "input" masses of pollutants to the flare are destroyed by the flare with a certain rate of efficiency – the control efficiency or CE referred to earlier. For all of the hydrocarbon pollutants in the waste gas, Exxon assumes that the CE is 98 or 99% – i.e., the flare destroys 98 or 99% of the mass of these pollutants. This same assumption is used for all flares and for all emission events. Exxon also assumes that all incoming sulfur compounds, such as H2S, are "destroyed" – i.e., converted to SO2 – at a rate of 98%. Thus, the remaining 1% or 2% of the pollutant mass in the incoming waste gas (i.e., the "1 minus CE" fraction) is assumed to be released to the atmosphere. It is this 1% or 2% of input that is reported in the STEERS reports as the amount released to the atmosphere (as long as it exceeds a reportable threshold quantity) and it is this 1% or 2% figure that is modeled by SAGE in order to determine if the release event can cause an adverse impact outside the Complex.

As I have noted above, I have reviewed numerous STEERS reports, TCEQ investigation reports, and corresponding SAGE reports for events that occurred during the time of interest in the present matter involving flare releases at the Refinery, the Chemical Plant and the Olefins Plant in the Complex. Based on the review of these documents, as well as related documents (such as

Exxon's Notifications to the TCEQ, its emission calculations, associated TCEQ investigation reports, Exxon's responses to information requests from TCEQ, and correspondence), and the SAGE reports (where available), I can state the following as generally true:

(a) the root cause analyses by Exxon of most of these "upset" events generally point to avoidable causes such as poor equipment design, poor maintenance, or inadequate inspection, etc. However, in this report, I am not providing opinions on the causes of such events;

(b) the calculation of the quantities of the various pollutants, whether conducted by Exxon or by SAGE, are not reproducible since almost all of the required basic data, such as underlying periodic flow rates, temperatures, gas flow compositions, etc., are not provided in the reports. Generally, only the summary results of the calculations for each event (typically, the total lb/event of each pollutant) are provided, from each emission point, such as from each flare. As examples, see the STEERS information summarized in Attachment F;

(c) it is not clear to me how TCEQ could have verified the accuracy of the calculated/reported emissions for any of the events without the underlying process data;

(d) as mentioned earlier, Exxon has uniformly used either 98% or 99% (for a subset of the more reactive hydrocarbon pollutants) as the CE for all flares, at all times, for all events. TCEQ has never, to my knowledge, questioned this fundamental and critical assumption;

(e) Exxon has never estimated nor included numerous pollutants (PICs) that can be created by the flares in any of the reports. While it has estimated emissions of some PICs, such as CO and NOx, it has not done so for many others known to be created in refinery and chemical plant flares. As I will briefly discuss later, burning hydrocarbons in any combustion system (including in the most controlled circumstances) can create numerous additional PIC compounds, typically toxic air pollutants. This is so because of the complex nature of the combustion process itself. Flares, as I will also discuss later, are far from controlled combustors. Thus, they can and do create numerous additional compounds. Exxon has never quantified nor included these additional compounds. To the extent it has not, emissions reported by Exxon are under-reported based on this fact alone;

(f) Exxon has never directly measured or attempted to measure, by any technique, the emissions of various pollutants from any of its flares or the CE of any of its flares.[13] Instead, as explained by Exxon, "ExxonMobil applies current and relevant agency guidance on estimating flare emissions, including TCEQ's guidance document entitled 'Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers RG-l09'. Several studies have demonstrated high efficiency of properly designed and operated industrial flares. Most flare studies refer to two landmark programs: the 1982-1986 EPA/CMA/EER program and the 1996-2004 University of Alberta program. The Texas Commission on Environmental Quality ("TCEQ") is currently sponsoring and conducting several additional studies regarding flare efficiency."[14] I specifically note the condition "properly designed and operated" referred to by Exxon;

(g) the dispersion modeling conducted by SAGE includes as a critical input the various pollutant emission rates calculated by Exxon (or SAGE) as discussed above. Thus, any errors or uncertainty or omissions in the emission rate estimates will directly affect the results of the modeling analysis, even assuming that all of the other modeling assumptions by SAGE are correct;

(h) the SAGE modeling analysis uses, in every instance (i.e., for each event for which SAGE conducted modeling) inappropriate flare characteristics such as the flare exit velocity and temperature – which will affect the dispersion characteristics of the exhaust from the plume, and resultant ambient impact concentrations. Although SAGE relies on TCEQ (or agency predecessor TNRCC) guidance for such assumptions, such reliance is inappropriate, as I will discuss later;

(i) in most instances, especially for the numerous toxic compounds that are emitted by the flares, the impacts analysis assumes that background concentrations of such compounds is zero – not because this is true or likely to be true, but because no background measurements are available.

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[13] See Defs. Objections and Answers to Plaintiffs First Set of Interrogatories. In response to Interrogatory No. 2, which was "Describe the basic methodology and the results of any on-site studies, tests or monitoring that have been conducted to determine the combustion efficiency (also known as "destruction efficiency") of the Baytown Complex's flares, including the dates of such studies, tests or monitoring." Exxon's response was "….ExxonMobil responds that ExxonMobil has performed no on-site studies, tests or monitoring of the Baytown Complex's flare combustion efficiency."

[14] Ibid.

Collectively, the facts above render meaningless any attempt by Exxon to conclude, which it does for each event, that the impacts of emissions due to the event are not significant. To the contrary, as I will discuss below, given the significant shortcomings of its emission calculations and dispersion modeling assumptions, it is simply impossible to conclude that Exxon's impacts assessment is correct, or even "conservative" as it repeatedly asserts. It is more likely that actual unauthorized emissions from the flares during these reportable events is much greater than what Exxon has estimated. For this reason alone, predicted impacts are likely to be significantly greater than what Exxon or SAGE have estimated.

In terms of detail, I will focus on three areas below:

First, I will discuss whether or not the flare control efficiency is likely to be 98 or 99%, as Exxon has assumed. Second, I will provide a brief discussion to support the well-known fact that PICs are inherently produced by all combustion systems, including flares, and by omitting them Exxon has under-predicted emissions from these events. Lastly, I will show why certain modeling assumptions by SAGE are inappropriate.

IV FLARES, CONTROL EFFICIENCY, AND EMISSIONS

Flares, particularly the type at issue here (namely, open flares), are not emission control devices. Their primary purpose has always been to be a safety device so that, if necessary, large quantities of process gases can be rapidly and safely vented, thereby protecting process equipment from hazards such as explosions.

Since they have flames, however, they can "destroy" hydrocarbon compounds if present in the flared gas and they can convert (i.e., oxidize) sulfur compounds into sulfur dioxide and other compounds. However, the key question is not whether such conversion/oxidation *can* occur. Rather, the key question is to what extent can flares reliably and consistently maintain a particular control efficiency, such as the 98% or 99% assumed by Exxon.

That Exxon has assumed these efficiencies in its calculations is evident from the following examples, which are representative of Exxon's practice over the time period and events I have examined.

For the event with the STEERS tracking number 134509 at the refinery, Exxon provides the following in support of its emission calculations:[15]

Sample Calculation for Flare Emissions from FS-20

Flare DRE = 98 % H2S to SO2

Total scf flare gas * (X mol % H_2S / 100) * 34.1 lb H_2S/lb mol H_2S / (379 lb mol/scf) * 0.02 = Total lb H_2S emitted from Flare

Total scf flare gas * (X mol % H_2S /100) * 34.1 lb H_2S/lb mol H_2S / (379 lb mol/acf) * 0.98 * (1 lb mol H_2S/ 1 lb mol SO_2) * (64.0648 lb/lb mol SO_2) / (34.1 lb / lb mol H_2S) = Total lb SO_2 emitted from Flare

For event #126041 at the refinery, Exxon provides the following in its emission calculations:[16]

[15] EOMCS00025921
[16] EOMCS00024773

Sample Calculation for Flare Emissions

Total Event Emissions
2,880,980 acf flare gas * 0.253 mol % H_2S * 34.1 lb H_2S/lb mol H_2S / (379 lb mol/acf) * 98% DRE =
13.27 lb H_2S emitted from Flare

2,880,980 acf flare gas/min * 0.253 mol % H_2S * 34.1 lb H_2S/lb mol H_2S / (379 lb mol/acf) * 98% DRE H_2S to SO_2 * (1 lb mol H_2S/ 1 lb mol SO_2) * (64.0468 lb/lb mol SO_2) / (34.1 lb / lb mol H_2S) =
1,221.17 lb SO_2 emitted from Flare

Total Unauthorized Emissions
2,880,980 acf flare gas * 0.237 mol % H_2S * 34.1 lb H_2S/lb mol H_2S / (379 lb mol/acf) * 98% DRE =
12.26 lb H_2S emitted from Flare

2,880,980 acf flare gas/min * 0.237 mol % H_2S * 34.1 lb H_2S/lb mol H_2S / (379 lb mol/acf) * 98% DRE H_2S to SO_2 * (1 lb mol H_2S/ 1 lb mol SO_2) * (64.0468 lb/lb mol SO_2) / (34.1 lb / lb mol H_2S) =
1,129 lb SO_2 emitted from Flare

For event #101998 at the Olefins plant, Exxon provides the following as support for its emission calculations:[17]

ExxonMobil Chemical Corporation
Baytown Olefins Plant
January 3 - 5, 2008 Emission Event, Incident No. 101998
Specification of Material Flow to EPN: FLARE1

Chemical	Emissions (after control)	Control Efficiency	Flow (to control)	Low Heating Value-LHV	Molecular Weight-MW	Density	Weight Percent in the Stream
	(lbs)	(%)	(lbs)	(btu/lb)	(lb/lb-mol)	(lb/scf)	(%)
Hydrogen	1,056	99%	105,605	51,571	2.0159	0.0053	3.80
Ethylene	6,673	99%	667,331	20,276	28.0538	0.0746	23.99
Ethane	3,117	99%	311,682	20,416	30.0697	0.0803	11.20
Methane	4,187	99%	418,663	21,502	16.0428	0.0424	15.05
Propane	369	99%	36,855	19,929	44.0966	0.1196	1.32
Propylene	6,940	99%	694,039	19,683	42.0807	0.1110	24.95
Acetylene	77	99%	7,742	20,734	26.0379	0.0697	0.28
1-Butene	0	98%	0	19,484	56.1076	0.1480	0.00
Isobutane	47	98%	2,332	19,614	58.1235	0.1582	0.08
Isobutylene	1,393	98%	69,644	19,532	56.1076	0.1480	2.50
Toluene	868	98%	43,423	17,487	92.1402	0.2431	1.56
1,3-Butadiene	1,356	98%	67,778	19,375	54.1000	0.1427	2.44
t 2 Butene	299	98%	14,936	19,397	56.1076	0.1480	0.54
c 2 Butene	184	98%	9,195	19,471	56.1072	0.1480	0.33
n Butane	181	98%	9,036	19,665	58.1235	0.1582	0.32

The table shows control efficiency of 99% (for the highly reactive VOCs) or 98% (for the other compounds). However, it is not clear what the "weight percent in the stream" column refers to since the event took place over 3 days. What does this average mean when actual flows and concentrations are likely to have fluctuations, and CE depends on the instantaneous values of these parameters?

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[17] EOMCS00008576 (Flare 1) and also similar table for Flare 2 at EOMCS00008777.

In connection with event #69875 at the Olefins plant, Exxon notes that:[18]

Actions Taken, of Being Taken, to Minimize Emissions and/or Correct the Situation:
Vented emissions to Flare 1 and Flare 2 which provide 98%+ destruction efficiency, shut down LC-02 to make repairs.

It is important to note at the outset here that relatively small changes in flare control efficiency can have dramatic impacts on emissions to the atmosphere. This is best illustrated via an example. Let us assume that 100 pounds per hour (lb/hr) of a given pollutant are sent to the flare system. Let us consider how the emissions to the atmosphere of this pollutant are affected when there is a change in the control efficiency of the flare from 98% to, say, 97%. When the flare efficiency is 98%, that means that 98% of the pollutant mass is combusted and only 2%, or 2 lb/hr in our example, of the pollutant are emitted. But when the flare efficiency drops to 97%, the emissions to the atmosphere are now 3 lb/hr. Thus, a drop in the efficiency of the flare from 98% to 97% causes the emissions to the atmosphere to increase from 2 lb/hr to 3 lb/hr – a 50% increase. Thus, what seems, at first glance, to be a relatively small reduction in flare control efficiency has, in fact, a dramatic impact on the emissions to the atmosphere. In the same example, if the flare efficiency were to drop from 98% to 93%, the emissions to the atmosphere increase from 2 lb/hr to 7 lb/hr, an increase of 5 lb/hr or 250%. When tens or hundreds of thousands of pounds of emissions are at stake, as is the case in many of Exxon's emission events, even the slightest reductions in flare efficiency will have dramatic consequences for actual emissions.

The issue of control efficiency of open flares, whether steam assisted or not, has been studied by various researchers in the last three or so decades. While many of these studies, all of which have been, of necessity, conducted in smaller, controllable, pilot-type settings, have demonstrated that high control efficiencies can be achieved by flares, none of them have demonstrated that it is possible to consistently maintain the conditions that would be required in order to maintain the control efficiency at some specified threshold such as 98% or 99%.

The 98% control efficiency value is typically relied on by flare operators because it happens to be part of various regulations.[19] Yet, these regulations do not fully capture the complexity of

[18] EOMCS00007070

actual flare operating conditions; and, in many instances, they are conditional. Thus, one cannot simply assume a certain, high control efficiency, without also carefully considering the operating conditions of the flare. Even Exxon, in its Interrogatory Response, recognizes the need for "properly designed and operated" flares.

More fundamentally, destruction of hydrocarbons in combustion systems requires three critical factors (often referred to as the "three Ts" of combustion): a minimum specified temperature, residence time at temperatures greater than this minimum specified temperature, and turbulence, which increases the residence time.[20] Properly designed combustion control systems can achieve very high control efficiencies as long as they can be designed to maintain the minimum temperature and the required residence time (the length of time the compound remains in the presence of the required temperature), both of which are compound-specific. Basically, the longer the residence time and the higher the temperature, the greater the ability to achieve higher destruction or control efficiency. Again, I must emphasize that destruction or control efficiency is pollutant- or compound-specific: different pollutants require different temperature and residence times for destruction.

Theoretical models that correlate control efficiency, residence time, and temperature are available. For example, one well known text notes, "Lee and coworkers, in two studies [citations omitted], conducted experiments on several VOCs and proposed a purely statistical model to predict the temperatures required to give various levels of destruction…. Their model depends on a number of properties of the VOC, the most important of which are the autoignition temperature, the residence time, and the ratio of hydrogen to carbon atoms in the molecule."[21] Discussion provided in this reference book confirms that residence time (in a temperature zone

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[19] Specifically, flares operated consistent with regulations at 40 CFR 60.18 may assume a 98% combustion efficiency. However, there is little technical justification for this regulation. The 98% value is based on AP-42 Section 13.5, Flares, which in turn is based on a 1983 EPA study. An extensive body of experimental studies on flare combustion efficiency has been developed over the past two decades. Based on these studies, it was generally assumed that flares operate with high efficiency—98% and higher. However, these 98%+ control efficiencies were measured at flares burning dry, high heat-content hydrocarbon gases, under low to moderate wind conditions. See Castiñeira, supra note 100, at ch. 1 (see literature review) available at http://www.lib.utexas.edu/etd/d/2006/castineirad34242/castineirad34242.pdf. These ideal conditions rarely exist at refineries.

[20] See, for example, Baukal, Charles E., et. al, The John Zink Combustion Handbook, Section 11.2, p. 352.

[21] Cooper C. David and F. C. Alley, Air Pollution Control – A Design Approach, Second Edition, Waveland Press, p. 345-346.

that exceeds a particular threshold temperature), among other parameters, is a key input that determines destruction efficiency. It also notes that, for a given temperature and residence time, destruction efficiency will vary by pollutant.

The problem is that, for open flares, one cannot be certain as to (1) the spatial and temporal temperature-field at the flare, or (2) the residence time that a specific compound experiences. This is because both of these factors depend on numerous additional factors, including the geometry of the flare tip, the manner in which the flare's waste gas is introduced, the manner in which the steam assist gas is introduced, the location of the pilot flame, the flow rates of the waste gases and the steam assist, the manner in which the steam and waste gas streams mix, the respective temperatures of the waste and steam assist streams, the chemical composition of the waste gas (since that will determine the amount of heat released by the flame), the local pressure field in the open flare, the location and fluctuation of the flame(s), the cross-wind velocity and direction and its fluctuation over time, and many other factors. In other words, one cannot depend on a particular minimum residence time and nor can one rely on a defined temperature field in the combustion zone, since both will vary based on all of these parameters and many others.

Thus, control efficiency will vary – and vary considerably. It is for this reason that flares cannot be considered to be pollution control devices, where one can rely on achieving a required minimum control efficiency at all times. Any "control" achieved in a flare is purely a co-benefit or incidental to the primary purpose of it being a safety device.

Making the problem even more complex, actual operating flares are difficult to directly test. Thus, real-world confirmation of control efficiency has, to date, not been possible even under limited circumstances.[22] Thus, all surrogate approaches to testing, such as smaller controlled

[22] See "Emissions from Elevated Flares – A Survey of the Literature," by P. Gogolek, A.Caverly R. Schwartz, CanmetENERGY- Ottawa John Zink Company LLC, J. Seebold J. Pohl, Consultant Energy International, prepared for the International Flaring Consortium, April 2010. "There are numerous difficulties in taking measurements from operating industrial flares. These include very high stacks (100 m or more), dangerous heat radiation to personnel and varying flame position due to changing flare gas flow rates and wind speed. The measurements on an operating flare give sparse coverage of the range of possible operating conditions and makes scientific conclusions difficult. This requires measurements to be taken on pilot-scale flares with controlled operating conditions or using remote sensing technology." However, such confirmation has, to date, not been possible with remote sensing technologies such as Differential Adsorption LIDAR (DIAL) and other similar approaches.

experimental settings and indirect measurements, raise a host of other issues, including representativeness to actual flares. Even so, these studies do point out the sensitivity of various operating parameters, such as the need to maintain flame stability, that can directly affect control efficiency. And, over the years, some of these studies have resulted in the development of certain rules of thumb (such as the proper ratios of steam to assist gas, or minimum heating values, or specific velocities of the exhaust gases, minimum hydrogen content of the flare gas, etc.) as potential surrogates for actual, measured control efficiency. I stress that none of these surrogates has been demonstrated to be fully effective in predicting control efficiency. Yet they are used because there are no other better options.

Numerous recent studies do, however, call into question the uniform application of 98% combustion efficiency. Flare performance is impacted by operating parameters that were not specifically evaluated in the earlier studies, including: meteorological conditions, variable waste gas flow rate and composition, flare physical design, general maintenance, and steam and air assist operation.[23] Liquid droplets, low gas heating values, high crosswinds, and too much steam or air injection can all reduce the efficiency of flares, resulting in significant emissions. Thus, the constant 98% combustion efficiency is not reliable across the full range of real-life flare operating conditions. Much lower flare combustion efficiencies due to these factors have been confirmed in simulations, wind tunnel experiments,[24] and full-scale field investigations. These factors typically cannot be controlled during flaring emergencies like the various events at issue in this case.

First, let us consider crosswind velocity. Wind cannot be controlled by the operator and has a major effect on combustion efficiency above 5 - 7 mph.[25] I have evaluated wind speed data for the various dates that the example events shown in Attachment F occurred. Wind speeds, even at the surface, were in most cases greater than 5-7 mph. Of course, since most of the flares from

[23] Tex Comm'n Envtl. Quality, Flare Task Force Draft Report 6 (Sept. 3, 2009).
[24] 118 David Castiñeira, Modeling and Control of Flare Combustion Systems (unpublished powerpoint presentation, University of Texas, Austin), available at http://www.che.utexas.edu/twccc/presentations0206/castineira-talk0206.pdf.
[25] U.S. Envt'l Prot. Agency, VOC Fugitive Losses: New Monitors, Emissions Losses, and Potential Policy Gaps, ix, 24, 40 (Oct 25-27, 2006), available at http://www.epa.gov/ttn/chief/efpac/documents/wrkshop_fugvocemissions.pdf ("When the wind speed is greater than five miles per hour, flare efficiency drops significantly. The emission factor for flare estimation is based on a flare operating in still air conditions, hence it is likely to underestimate emissions.")

which emissions occurred are several hundred feet tall, and wind speed increases rapidly with height above ground surface, actual wind speeds at the flare height are considerably greater.[26] Combustion efficiency is reduced as high cross wind velocities bend the flame over, allowing significant amounts of fuel to be stripped away from the burner exit. High wind velocity also reduces flame size, which reduces the amount of oxygen entrained into the flame; that allows burning in detached pockets over the tail flame length. These factors reduce combustion efficiency.[27] Thus, wind is a critical factor to account for when determining combustion efficiency. Yet, there is no discussion of wind speeds in Exxon's calculations, where 98% has been assumed to be the minimum control efficiency under all conditions, at all flares, for all events.

Second, consider exit gas velocity. Other work indicates that higher exit gas velocity may lead the flame to near blowoff conditions[28] and even to complete extinction of the flame if the gas velocity gets too high. Others have likewise concluded that for high-momentum flares, those with high gas-to-crosswind ratios, the flame is unlikely to attach to the stack, lowering combustion efficiencies.[29] Yet, Exxon's calculations do not include any calculations for stack exit velocity, which could be developed from process data and flare geometry.[30]

Third, consider the ratio of steam to waste gas. Studies in the 1980s "demonstrated that assist gas to waste gas mass ratios between 0.4 and 4 were effective in reducing soot while ratios between 0.2 and 0.6 achieved the highest hydrocarbon destruction efficiency."[31] While noting that the "highest hydrocarbon destruction efficiency" referred to may still be below 98%, it is

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[26] Milton R. Beychok, Fundamentals of Stack Gas Dispersion, 100 (3rd ed. 1994).

[27] See, e.g., M.R. Johnson & L.W. Kostiuk, Efficiencies of Low-Momentum Jet Diffusion Flames in Crosswinds, 123 Combustion and Flame 189, 199 (2000) ("Results show that increased crosswind speed () adversely affect the combustion efficiency...Gas chromatographic analysis of the products of combustion showed that the inefficiencies result from fuel stripping, and photographic images link this process to the occurrence of the flame burning in detached pockets over its full length and the shortening of the flame tail.").

[28] By "blow-off" I mean conditions that cause the flame to detach from the flare-tip and to tend towards extinction.

[29] David Castiñeira and Thomas F. Edgar, Computational Fluid Dynamics for Simulation of Wind-Tunnel Experiments on Flare Combustion Systems, 22 Energy & Fuels 1706 (2008).

[30] I note that the SAGE modeling for every event assumes a default velocity of 20 meters/sec, relying improperly on a regulatory default value. Clearly, actual exit velocities cannot be constant over time, even for a single flare, given the varying steam and waste gas flow rates and compositions, much less constant for all flares for all events, as SAGE has assumed.

[31] EPA 1983 Flare Study, as discussed in Reducing Flare Emissions from Chemical Plants and Refineries - An Analysis of Industrial Flares' Contribution to the Gulf Coast Region's Air Pollution Problem, May 23, 2005, Industry Professionals for Clean Air, p.4.

clear that too much assist gas (over-steaming or over-aerating) "may ... reduce the overall combustion efficiency by cooling the flame to below optimum temperatures for destruction of some waste gas constituents, and in severe cases may even snuff the flame, thus significantly reducing combustion efficiency and significantly increasing flare exhaust gas emissions." The EPA 1983 Flare Study noted: "Combustion efficiencies were observed to decline under conditions of excessive steam (steam quenching) and high exit velocities of low Btu gases.[32] Exxon provided steam and waste gas flow rates for the flares associated with the events in question. For some of the example events in Attachment F, I have investigated how these ratios varied during specific events, at specific flares. Attachment G shows the analysis (note that Attachment G is not an exhaustive analysis of the ratios, since all of the data was provided in non-native file format, requiring resource-intensive analysis). As seen in Attachment G, in numerous instances, at various flares, the steam to waste gas ratio was considerably higher (and in a few cases, considerably lower) than the 0.2-0.6 ratio which would provide the highest CE. It is my opinion that the control efficiency of the flares under the very high steam assist to waste gas ratios would be very low. Overwhelming amounts of steam along with small quantities of waste gas would simply result in very low temperatures or possibly outright flame-quenching, thus providing no control (in other words, a CE of 0%). Prior studies have indicated that control efficiencies drop dramatically as this ratio increases – for example, it is less than 70% when the ratio is around 6 or 7.[33] During periods when CE is only 70%, actual emissions of pollutants such as H2S and VOCs would be 35 times greater than amounts reported by Exxon using an assumption of 98% efficiency. And, control efficiency would be lower still for some of the steam to gas ratios shown in Attachment G, which are much greater than 7.

Further, in instances where a flare is operated in smoking conditions or there are flame outages, as reported by Exxon in numerous instances, the control efficiency would be low or zero (for example under flame outage conditions). Attachment H lists numerous instances where flares were reported as smoking, with 100% opacity (smoke so thick that light cannot pass through it). Attachment I lists numerous instances where the pilot flame was reported to be out.

[32] EPA 1983 Flare Study, p. ii., as discussed in Reducing Flare Emissions from Chemical Plants and Refineries - An Analysis of Industrial Flares' Contribution to the Gulf Coast Region's Air Pollution Problem, May 23, 2005, Industry Professionals for Clean Air.

[33] See presentation entitled Reducing Emissions from Plant Flares," by Industry Professionals for Clean Air – Houston, slide 9.

Exxon (and the TCEQ, in their review and acceptance of this assumption) is apparently relying on federal regulations at 40 CFR 60.18 in support of its 98% CE assumption; nonetheless, this assumption is factually, scientifically, and fundamentally incorrect.[34] As explained by ConocoPhillips in comments to the TCEQ: "The operating parameter efficiency envelopes have not been developed to account for wind nor the chemical properties of the gases flared nor for the amount of smoke-suppressing steam employed. Recent studies of hydrogen or inerts in the flared gases have demonstrated that energy content (Btu/scf) alone is a poor descriptor even though it is relied upon in the USEPA's 40 CFR 60.18."[35]

In fact, 40 CFR § 60.18, rather than assuring 98% combustion efficiency, invites conditions that can reduce flare combustion efficiency. The federal New Source Performance Standard (NSPS) for flares was designed to address "smoking flares," and thus requires flares to be designed and operated with no visible emissions. Smoke suppression is typically accomplished by injecting steam or air into the combustion zone to promote turbulence to mix and draw more air into the flame. An operator typically has no way to judge the proper amount of steam or air to add during a release, as that depends on many variables that may not be known or cannot be controlled, such as crosswind velocity. Thus, refineries commonly set the steam-to-flare gas ratio high to ensure smokeless operation under high flow conditions. This results in high steam-to-gas ratios during low flow and normal operations and sometimes even during emergency flaring. Thus, efforts designed to comply with 40 CFR § 60.18 (i.e., to minimize visible emissions) can actually decrease combustion efficiency.

I also recognize that the TCEQ's own regulations regarding flares that burn highly reactive VOCs (HRVOCs) assign an assumed 93% destruction efficiency to flares for which continuous

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[34] Operating conditions for flares are specified at 40 CFR 60.18(b) through (d); and 40CFR 63.11(b). The rules require that flares be designed for, and operated with, no visible emissions, except for periods not to exceed a total of five minutes during any two consecutive hours. In addition, the flare specifications require that the flare must be operated with a flame present at all times. The presence of a flare pilot flame is to be monitored to ensure that a flame is present at all times. The minimum net heating value of the flared gas and the maximum exit velocity of steam-assisted, air-assisted, and non-assisted flares are specified in a table. An equation is provided to calculate the maximum exit velocity for non-assisted and steam-assisted flares. Additionally, at 40CFR60.18(c)(3)(ii), EPA specified the minimum net heating value (Btu/scf) of the flared gas to assure flame stability and high destruction efficiency.

[35] Comment from ConocoPhillips to TCEQ (May 9, 2009) (attachment contains James Seebold et. al., Practical Implications of Prior Research on Today's Outstanding Flare Emissions Questions and a Research Program to Answer Them, AFRC-JFRC 2004 Joint International Combustion Symposium).

monitoring data indicates a failure to meet the EPA's standards for minimum heat content and maximum exit velocity.[36] But it is not clear why TCEQ did not require, and Exxon did not calculate, the exit velocities for the various flaring events, as a function of time. Since I did not have the underlying process data, I could not do this calculation.

In summary, it is telling that a recent survey of flare research noted the following.

"The major variables affecting flare performance are:

- Composition of flare gas.
- Flow rate of flare gas.
- Wind speed.
- Steam or air rate for assisted flares.
- Flare tip size.
- Flare tip design and configuration.
- Flare tip exit velocity.
- Pilot stabilization."[37]

In addition, the overall maintenance condition of the flare, including all of the its components – such as the steam-assist ring, the ignition system, etc. – also play a major role in affecting flare performance.

Yet, in assuming that 98% CE is appropriate at all times, Exxon did not discuss or provide any analysis of any of these factors.

It is my opinion, based on the discussion above, that using 98% is inappropriate and factually incorrect and is likely to lead to a significant underestimate of actual emissions during the flaring events in question.

Given the uncertainties alluded to in the discussion, it is my opinion that a more proper (and still likely conservative) CE value would be 93%, as noted in the TCEQ regulations for the destruction of VOCs. As noted above, this figure would still be far too high for instances when the steam to waste gas ratio is very high (see Attachment G for examples), when the flares were smoking (see Attachment H for examples), and when there are pilot flame outages (see

[36] See 30 TAC 115.725(d)(7).

[37] "Emissions from Elevated Flares – A Survey of the Literature," by P. Gogolek, A.Caverly R. Schwartz, CanmetENERGY- Ottawa John Zink Company LLC, J. Seebold J. Pohl, Consultant Energy International, prepared for the International Flaring Consortium, April 2010.

Attachment I for examples). In addition, while this level could also be too high in other instances, such as when there are high cross-wind velocities at the flare stack, a default assumption of 93% would nonetheless be much more realistic than the 98%/99% assumption used by Exxon. As I have discussed earlier, if one were to use 93% instead of 98% CE, that means that all emissions estimated by Exxon would have to be increased by a factor of 3.5. For those pollutants for which Exxon has used a CE of 99%, using 93% instead would increase their emissions by a factor of 7 times.

The implication of such emissions increases is significant. For example, consider Event 126041 at the refinery. Emissions for this event were calculated using a CE of 98%.[38] Even with this extremely optimistic assumption, the air dispersion impacts from this event were significant. As seen in the summary table prepared by SAGE,[39] "maximum" concentrations for butane, isopentane, and VOCs (as cyclohexane) were already predicted to be well over their respective standards (i.e., impacts for these pollutants were 192%, 178% and 163%, respectively, of the respective standards). H2S was predicted to be over 52% of its standard. However, if the actual CE was just 93% (and not lower still, which is entirely possible), then the emissions used in the modeling would have to be multiplied by 3.5 times and the resultant concentrations predicted by the model would also be 3.5 times greater, all other modeling assumptions being the same. Thus, the ambient air concentration of H2S would be 3.5*52%, or over 182% of the standard. The concentrations of butane, isopentane, and VOCs would each be more than five times higher than the standard.

Such revised emission estimates will directly impact the conclusions of all of the modeling conducted by SAGE using the artificially low Exxon-estimated emissions.

In addition, note that all of the above discussion only affects those pollutants that Exxon has actually considered, and not those additional PICs that can form in the flare combustion region. I will discuss that issue in the next section.

[38] See EOMCS00024773
[39] See EOMCS00024786

V. PRODUCTS OF INCOMPLETE COMBUSTION FROM FLARING

As discussed earlier, it is inherent in the combustion process that PICs will invariably form. Even in well controlled situations, involving single fuels, we see evidence of formation of PICs. For example, EPA noted that "[T]he formation of PICs during incineration processes is strongly influenced by mixing, which affects the instantaneous values of the reactant concentrations and of the temperature in the combustion chamber." [40]

EPA's compilation of emission factors, AP-42, provides additional evidence. Even when burning a simple and "clean" fuel such as natural gas (which is mostly methane), EPA notes that the following organic compounds can form (since they were not present in the fuel to begin with) in the combustion process: 2-Methylnaphthalene, 3-Methylchloranthrene, 7,12-Dimethylbenz(a)anthracene, Acenaphthene, Acenaphthylene, Anthracene, Benz(a)anthracene, Benzene, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(g,h,i)perylene, Benzo(k)fluoranthene, Butane, Chrysene, Dibenzo(a,h)anthracene, Dichlorobenzene, Ethane, Fluoranthene, Fluorene, Formaldehyde, Hexane, Indeno(1,2,3-cd)pyrene, Naphthalene, Pentane, Phenanathrene, Propane, Pyrene, and Toluene.[41] Most of these are highly toxic aromatic or poly-aromatic hydrocarbons.

Burning more complex mixtures will result in many more compounds being created. There is direct evidence of that as well. In a prior study done by the Petroleum Environmental Research Forum (PERF), involving gaseous hydrocarbon external combustion,[42] numerous hydrocarbon compounds were detected and quantified, including: Acetaldehyde**,** Formaldehyde**,** Acrolein**,** Acetone**,** Propanal**,** Methylethylketone**,** Benzaldehyde**,** Isopentanal**,** Pentanal**,** o-Tolualdehyde**,** m-Tolualdehyde**,** p-Tolualdehyde**,** Hexanal, Acetylene**,** Ethylene**,** Ethane**,** Propyne**,** Propane**,** Propylene**,** 1,3-Butadiene**,** 1-Butene**,** cis-2-Butene**,** Butane, 1-Butene, Benzene**,** Toluene**,** Hexane**,** mp-Xylene**,** Heptane**,** Octane, Naphthalene**,** Acenapthylene**,** Acenaphthene**,** Phenanthrene**,**

[40] http://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractDetail/abstract/5761
[41] See AP-41, Table 1.4-3. Available at http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.
[42] 19 The Origin and Fate of Toxic Combustion Byproducts in Refinery Heaters: Research to Enable Efficient Compliance with the Clean Air Act, Petroleum Environmental Research Forum Project 92-19, Final Report, August 1997; Links:http://www.epa.gov/ttn/atw/iccr/dirss/perfrept.pdf ; http://www.epa.gov/ttnatw01/iccr/dirss/perfrept.pdf;

Anthracene, Fluoranthene, Pyrene, Benzo(b)fluoranthene, Benzo(e)pyrene, Indeno(1,2,3-cd)pyrene, Benzo(g,h,i)perylene, Benzo(a)pyrene, and Coronene.

While Exxon has included some PICs in its estimates, such as 1,3-Butadiene, it has not accounted for the vast majority of these compounds, nor made a technical case (which it cannot do) that these and other PICs would be absent in the flare emissions.

Thus, Exxon's emission estimates are inadequate and flawed in this regard. And, as a result, the modeling conducted using the Exxon-estimated emissions are also flawed.

VI. IMPROPER MODELING ASSUMPTIONS

In this section, I will point out several improper modeling assumptions that make the conclusions of the modeling performed by Exxon and SAGE (even if one were to assume that all of the other factors, such as the flawed emission inputs, were correct) unreliable.

I first note that Exxon and its consultants had available to them specific process and flare design information such as flare geometry (tip diameter, etc.), as well as waste gas flow rates, steam flow rates, process gas chemical composition, temperatures of the steam and waste gas flows. Using this information, Exxon and SAGE could have calculated exhaust gas temperatures and exit velocities, which are both critical input parameters used in the EPA-approved model (SCREEN Version 3.0) that SAGE used to conduct its impact analysis.

Yet, in every instance (i.e., for every event and for every flare) that I was able to verify, SAGE used default values for the exit temperature (1273 K) and velocity (20 meter/sec). Representative examples are shown below.

For event #134509 at the refinery, the excerpt from the SAGE report shows that the exit velocity for Flare 20 was 20 m/s and the temperature was 1273 K.[43]

ExxonMobil Refining & Supply Co.
Baytown Refinery
Emission Event January 14-21, 2010; Incident No. 134509
Summary of SCREEN3 Modeling Input Data and Parameters for Point Sources

Source ID	Emission Point Common Name	Scenario	Downwash Effects?	Min. Distance	Stack Height		Stack Diameter		Exit Velocity		Temperature		Generic Emission Rate	
				(meters)	(feet)	(meters)	(feet)	(meters)	(ft/s)	(m/s)	(deg F)	(deg K)	(lb/hr)	(g/s)
FL20	Flare 20	All	No	759	304.0	92.659	8.88	2.71	65.62	20.0	1831.7	1273.0	1.000	0.126

For event #126041 at the refinery, the excerpt from the SAGE report shows that the exit velocity for each and every flare involved in that event (i.e., Flares 3, 4, 5, 6, 17, 20 and 21) was 20 m/s and the temperature of each flare was 1273 K.[44]

[43] EOMCS00025947
[44] EOMCS00024799

ExxonMobil Refining & Supply Co.
Baytown Refinery
Emission Event June 24-26, 2009, Incident No. 126041
Summary of SCREEN3 Modeling Input Data and Parameters for Point Sources

Source ID	Emission Point Common Name	Min. Distance	Stack Height		Stack Diameter		Exit Velocity		Temperature		Generic Emission Rate	
		(meters)	(feet)	(meters)	(feet)	(meters)	(ft/s)	(m/s)	(deg F)	(deg K)	(lb/hr)	(g/s)
Flare17	FLARE17	518	304.0	92.659	3.28	1.0	65.62	20.0	1831.7	1273.0	1.000	0.126
Flare20	FL20	759	304.0	92.659	3.28	1.0	65.62	20.0	1831.7	1273.0	1.000	0.126
Flare21	FL21	759	304.0	92.659	3.28	1.0	65.62	20.0	1831.7	1273.0	1.000	0.126
Flare3	FL3	510	252.0	76.810	3.28	1.0	65.62	20.0	1831.7	1273.0	1.000	0.126
Flare4	FLARE4	103	290.0	88.392	3.28	1.0	65.62	20.0	1831.7	1273.0	1.000	0.126
Flare5	FL5	203	248.0	75.590	3.28	1.0	65.62	20.0	1831.7	1273.0	1.000	0.126
Flare6	FL6	300	248.0	75.590	3.28	1.0	65.62	20.0	1831.7	1273.0	1.000	0.126

For event #101998 at the Olefins plant, the excerpt from the SAGE report shows that the exit velocity for both the primary and the secondary flares involved in that event was 20 m/s and the temperature was 1273 K.[45]

ExxonMobil Chemical Corporation
Baytown Olefins Plant
January 3 - 5, 2008 Emission Event, Incident No. 101998
Summary of SCREEN3 Modeling Input Data and Parameters

Source ID	Source Description	Incident No.	Incident Date	Min. Distance	Stack Height		Stack Diameter		Exit Velocity		Temperature		Propylene Emission Rate	
				(meters)	(feet)	(meters)	(feet)	(meters)	(ft/s)	(m/s)	(deg F)	(deg K)	(lb/hr)	(g/s)
FLARE1	Primary Flare	101998	1/3-5/2008	860	393	119.786	24.765	7.549	65.62	20.0	1832.0	1273.0	1.0000	0.1260
FLARE2	Secondary Flare	101998	1/3-5/2008	1,059	415	126.492	32.444	9.889	65.62	20.0	1832.0	1273.0	1.0000	0.1260

Notes: 1. For the flare effective diameter calculations, see the additional spreadsheet.
2. The effective flare diameters and emission rates are provided for the first hour of release with the highest material flow to both flares.

For event #69875 at the Olefins plant, the excerpt from the SAGE report shows that the exit velocity for both the primary and the secondary flare involved in that event was 20 m/s and the temperature was 1273 K.[46]

ExxonMobil Corporation
Baytown Olefins Plant
Summary of SCREEN3 Modeling Input Data and Parameters
January 1 - 16, 2006 Emission Event. Incident No. 69875. Day Time.

Source ID	Source Description	Incident No.	Incident Date	Min. Distance	Stack Height		Stack Diameter		Exit Velocity		Temperature		Generic Emission Rate	
				(meters)	(feet)	(meters)	(feet)	(meters)	(ft/s)	(m/s)	(deg F)	(deg K)	(lb/hr)	(g/s)
FLARE1	Primary Flare	69875	1/1/2006	853.4	393.00	119.79		17.054		20.00		1273.0	10.0000	1.2600
FLARE2	Secondary Flare	69875	1/1/2006	1048.5	415.00	126.49		18.800		20.00		1273.0	10.0000	1.2600

Note: For the flrare effective diameter calculations, see the additioal spreadsheet

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45 EOMCS00008573
46 EOMCS00007086

I note that each of these events lasted many hours or, in some cases, many days.

The actual values of these parameters cannot be the same for every flare, or even for one flare over the course of a single flaring event. The underlying steam and waste gas flows are not constant, and the composition of the waste gas stream is also not constant – much less the same for all events at all flares. Thus, right away, we can dispense with the notion that the model was run to characterize the actual event. On these grounds alone, the predicted results are unreliable.

As support for its use of these parameters SAGE references an older TCEQ guidance document,[47] which provides these default values. I note that this guidance is not currently available on the TCEQ website even though there are more than a hundred other guidance documents that are similarly available. I am therefore not sure that it is relevant as current TCEQ guidance. Nonetheless, this document simply states that "[F]lares are a special type of elevated source that may be modeled as a point source. The technique, to calculate buoyancy flux for flares generally follows the technique described in the *SCREEN3 Model User's Guide* (EPA, 1995b)." Thus, the RG-25 guidance properly references and directs the user to the SCREEN Model User's Guide, which is available on EPA's website.[48]

This guidance states that "[T]he SCREEN model calculates plume rise for flares based on an effective buoyancy flux parameter. An ambient temperature of 293K is assumed in this calculation and therefore none is input by the user. It is assumed that 55 percent of the total heat is lost due to radiation. Plume rise is calculated from the top of the flame, assuming that the flame is bent 45 degrees from the vertical.

"While building downwash is included as an option for flare releases, it should be noted that SCREEN assumes an effective stack gas exit velocity (vs) of 20 m/s and an effective stack gas exit temperature (Ts) of 1,273K, and calculates an effective stack diameter based on the heat release rate. **These effective stack parameters are somewhat arbitrary [**emphasis added**]**, but the resulting buoyancy flux estimate is expected to give reasonable final plume rise estimates for

[47] Air Quality Modeling Guidelines, prepared by New Source Review Permits Division, RG-25 (Revised), February 1999.
[48] EPA-454/B-95-004, SCREEN3 Model User's Guide U.S. ENVIRONMENTAL PROTECTION AGENCY, Office of Air Quality Planning and Standards, Emissions, Monitoring, and Analysis Division, Research Triangle Park, North Carolina 27711, September 1995, available at http://www.epa.gov/scram001/userg/screen/screen3d.pdf

flares. However, since building downwash estimates depend on transitional momentum plume rise and transitional buoyant plume rise calculations, the selection of effective stack parameters could influence the estimates. Therefore, building downwash estimates should be used with extra caution for flare releases. **If more realistic stack parameters can be determined, then the estimate could alternatively be made with the point source option of SCREEN. In doing so, care should be taken to account for the vertical height of the flame in specifying the release height…."** (pp. 15-16) (emphasis added).

In other words, in situations where more realistic stack parameters could have been determined (as is the case with Exxon's emission events), it is not necessary to use the arbitrary default values in the model. Instead, each flare release could have been properly modeled as a point source, with appropriately calculated release height and exit velocity and temperature values.

It is my opinion that, just on these grounds alone, the modeling conducted by SAGE is not reliable. Coupled with the greatly underestimated (and incomplete) emission rates used, the modeled impacts are even more unreliable and likely significantly under-predict the actual impacts from the various flaring events that at issue.

VII. REMEDIAL MEASURES

It is possible to significantly reduce instances of flaring and the amounts of waste gas that need to be flared. Such measures can reduce the emissions that result from flaring from both routine as well as non-routine events. Most of the refineries in California, both in the Bay Area (San Francisco) and the South Coast (Los Angeles area) have demonstrated this via the implementation of specific and detailed Flare Minimization Plans (FMPs), which are required pursuant to local rules and regulations.

Among other things, each FMP requires a thorough evaluation of each instance when flaring occurred that resulted in significant emissions. Based on root-cause analyses of such events, approaches to minimizing or eliminating such instances in the future are then identified. This may involve capital expenditures such as: the addition of backup waste gas compressors or other controls such as thermal oxidizers, to eliminate routine flaring; changes to operating procedures; changes to maintenance procedures, including more frequent maintenance; changes to training procedures, additional staffing, and the like. It also may include better planning in order to minimize flaring during scheduled events such as unit turn-arounds.

Fundamentally, flare minimization requires: (a) that events that cause or have caused flaring in the past be minimized or eliminated to the greatest extent possible by a thorough understanding of the root causes of these events; and (b) that there be sufficient capacity in the refinery to accommodate so-called "waste" gases, ideally by re-routing them, to the greatest extent possible, into other productive uses such as in the facility's fuel gas system. Thus, the need for adequate storage capacity and for maximum reliability of the compressors necessary for diversion of flare gases into the fuel gas system is paramount.

It is my understanding, based on my review of Exxon documents and information gained during my February 28, 2012, inspection of the Baytown Complex, that for at least 2 of the 5 flare gas systems at the Baytown complex there is currently no capability for such diversion – i.e., these systems do not have flare gas recovery capability. It is also my understanding that there is no/inadequate spare compressor capability for the other 3 systems, thus compromising their system reliability. These types of gaps can be addressed by proper capital expenditures. Each

flare gas system should have one main and one 100% backup compressor. Additionally, none of the flares should be burning a steady stream of waste gas – i.e., there should not be any routine flaring. For some of these systems, an appropriately sized thermal oxidizer should be considered, if these gases cannot be diverted to the fuel gas system.

It is instructive to see how others have minimized flaring. For example, FMPs for each of the refineries located in the Bay Area are provided in the Bay Area Air Quality Management District's (BAAQMD) web site.[49] This includes the Chevron, Conoco-Phillips, Shell, Tesoro, and Valero refineries. These FMPs are required to be updated annually and each updated FMP should "…incorporate[] new measures identified to reduce refinery flare emissions by reducing the frequency and magnitude of flaring events ('prevention measures'). Prevention measures identified must address flaring as a result of planned major maintenance, including startup and shutdown; flaring that may be reasonably expected to occur due to issues of gas quality or quantity; and flaring caused by recurrent failure of air pollution control equipment, process equipment, or processes."[50]

As the BAAQMD notes, FMPs should include "any new prevention measures identified as a result of an investigation into the cause of flaring events that have occurred since the previous FMP approval. Prevention measures identified must address flaring as a result of planned major maintenance, including startup and shutdown; flaring that may be reasonably expected to occur due to issues of gas quantity or quality; and flaring caused by recurrent failure of air pollution control equipment, process equipment, or processes. The FMP Updates are a key mechanism in the ground-breaking Flare Regulation to ensure continuous improvement towards minimizing flaring from the five Bay Area refineries by reducing the frequency and magnitude of flaring."[51]

The seven Los Angeles area refineries are also required to monitor their flaring emissions and to report flaring events when they exceed prescribed pollutant emissions or gas flow rates.[52] This includes the ExxonMobil refinery located in the City of Torrance.[53] It is worth noting that this refinery was not required to develop a FMP because "[T]his plan is only required if the facility

[49] http://www.baaqmd.gov/Divisions/Compliance-and-Enforcement/Refinery-Flare-Monitoring/Flare-Minimization.aspx
[50] *Ibid.*
[51] http://www.baaqmd.gov/Divisions/Compliance-and-Enforcement/Refinery-Flare-Monitoring.aspx
[52] http://www.aqmd.gov/comply/1118/notification.htm
[53] http://www.aqmd.gov/comply/1118/exxon.htm

exceeds the specific targets in any calendar year." Thus, since ExxonMobil did not exceed such targets – i.e., it was able to voluntarily implement measures to minimize flaring at this refinery – it did not have to submit such a plan. Although smaller than the Baytown refinery, the Torrance refinery is of roughly comparable age. I am not aware of any reason why approaches that Exxon is using at its Torrance refinery to minimize flaring could not be considered and implemented at the Baytown Complex.